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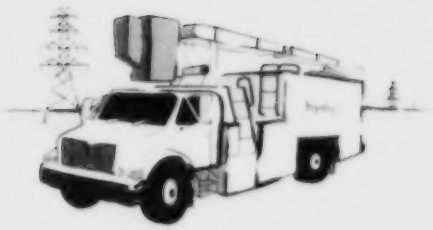


Putting power to work

Hydro One Annual Report 2006

hydro One

Consolidated financial

highlights and statistics

Year ended December 31 (Canadian dollars in millions)	2006	2005	Change	% Change
Revenues	4,545	4,416	129	3
Purchased power	2,221	2,131	90	4
Operating costs	1,395	1,279	116	9
Net income	455	483	(28)	(6)
Net cash from operations	889	1,169	(279)	(24)
Average annual Ontario 60-minute peak demand (MW)*	22,850	22,074	(434)	(2)
Distribution – units distributed to our customers (TWh)*	29.0	29.7	(0.7)	(2)

* Normalized for the impact of weather

Revenues
(Cdn $ millions)

Total Assets
December 31, 2006
(Cdn $ millions)

Net Income
(Cdn $ millions)

* Net income for 2004 includes a one-time regulatory recovery of $61 million

The Hydro One Family of Companies

Hydro One Inc.
The holding company for the businesses that operate in the electricity sector of Ontario. Hydro One Inc. owns and operates Hydro One Networks and Hydro One Brampton Networks. The businesses are overseen by each respective board of directors and regulatory requirements.

Hydro One Networks Inc.
Responsible for the operation and delivery of electricity which is regulated by the Ontario Energy Board. It is governed by the Electricity Act (Ontario) and the maintenance of the transmission and distribution networks.

Hydro One Brampton Networks Inc.
Provides electricity to one of the fastest growing communities in Ontario and 16 subsidiary entities in Canada.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario. Rates are not regulated by the province's electricity regulatory agency.

Hydro One Telecom Inc.
Markets and develops expertise in telecommunications and engineering that leverages the core electricity assets.

Our power at work

Customer satisfaction continued to climb in 2006, with

86%

of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

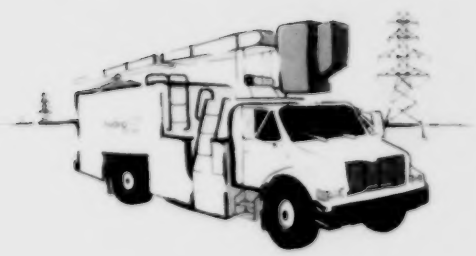
The North American Electric Reliability Council (NERC) awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

During a two-month period, three intense storms tested Ontario and knocked out power to more than 400,000 of our customers. The excellence of our restoration efforts earned us a prestigious *Emergency Recovery Award* from the Edison Electric Institute. This is the first time this award has gone to a utility based outside of the United States.

The Ontario Energy Board approved an increase of approximately

$160M

in our annual distribution revenue requirement. This decision demonstrates the OEB's confidence in our ability to maintain and operate Ontario's electricity system. The increased funds will enable us to make important investments we need in our distribution system.



Ensuring that Ontario continues to have the electricity delivery system that it needs and deserves.

This year, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, expertly meeting the operational challenges posed by multiple severe storms that affected many of our customers. The company embarked on several large projects to ensure the delivery of safe, reliable electricity to the people of Ontario.

The company's net income in 2006 decreased by $28 million, or 6%, to $455 million compared to 2005. This decrease primarily reflects increased expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, and lower transmission tariff revenues resulting from lower demand and changes to transmission regulations.

As Chair of Hydro One, I understand that the good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One's electricity delivery system. Hydro One was focused on new securities regulations this year and is now fully compliant with the strict new financial control and disclosure requirements.

We take our financial obligations seriously and our financial controls and disclosure practices are solid and undergo regular external scrutiny. We operate in a highly transparent manner. Hydro One has embraced all 13 recommendations of Ontario's Auditor General to improve compliance with our internal policies and procedures.

Hydro One made critical investments both in transmission and in distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Hydro One spent $1.7 billion in 2006 in total capital and operation, maintenance and administrative expenditures.

Our ability to arrange sufficient and cost-effective financing supports our improving long-term credit rating. This is vital to our ability to refinance maturing debt, fund capital expenditures and address other requirements. In particular, Hydro One has access to long-term funding that better matches our debt to our long-lived assets. The upgrades to our credit ratings reflect the confidence of the rating agencies and investors in the performance and management of the company.

The Board expects continued strong, stable financial performance and is confident in the management team's ability to meet the challenges in the coming year. In the past two years Hydro One has begun a major new construction phase and this will continue in the years ahead. Major projects vital to the economic well-being of Ontario are underway, including a new interconnection with Quebec, transmission upgrades in Toronto and the connection of new sources of generation as they become available across Ontario.

Hydro One paid its shareholder, the Province of Ontario, dividends of $350 million. Hydro One recorded $179 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

R. Burak

Rita Burak
Chair

Our work is complex, but the reason we do it is simple: Ontario depends upon Hydro One to deliver the electricity needed to put power to work.

Hydro One exists to ensure that the people, businesses, industries and communities of Ontario have the electricity they need to put power to work for them. Our transmission system represents more than 96% of Ontario's capacity.

We understand that our customers and other stakeholders expect Hydro One to be managed in a responsible manner, respecting the public trust placed in us to ensure the safe and reliable delivery of electricity at reasonable cost.

We take this trust seriously and believe that our performance and achievements of this past year bear this out.

Serving our customers drives everything we do. And our customers are diverse. From industrial giants like mining company Inco, Ontario's largest electricity consumer, to greenhouse operations in Leamington, to summer camps in Deep River and family homes in every corner of the province, we deliver electricity to a wide range of consumers.

In 2006, our customers told us that our service was better than ever. We made an honest appraisal of how we could do a better job of meeting our customers' needs, which enabled us to make major advances in improving our relationships. We have seen double-digit increases in customer satisfaction levels and we aim to reach customer satisfaction levels of 90%, on average, across all customer segments.

NERC gave our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The report singled out our industry-leading physical security procedures, infrastructure and program management as well as our innovative and fully integrated, multi-functional communications system.

We became the first utility based outside of the United States to receive the prestigious Edison Electric Institute *Emergency Recovery Award* recognizing the company's outstanding efforts in restoring power to more than 400,000 customers following three severe storms.

Our financial performance in 2006 was strong, with a net income of $455 million, and we paid our shareholder a healthy dividend.

As stewards of this province's massive and complex electricity transmission and delivery systems, we made significant progress on a number of critical system investment initiatives. We signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems. This $124 million investment will add an important new connection between the two grids and increase Ontario's ability to access electricity generated through renewable resources.

In November 2006, construction crews restored the Ontario to Michigan interconnection in the Sarnia area with the transmission operator in Michigan. This interconnection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of the existing high-voltage transmission system. This circuit will increase our import and export capacity by about 400MW and 200MW respectively.

We completed the excavation of a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative $45 million investment will carry an array of electricity transmission lines to tie the east and west sides of the city together with minimal disruption. This work will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

In 2006, we launched several new conservation and demand management programs in line with the Province's goal to create a culture of conservation in Ontario. Our programs mirror our customer base; some help Ontario families save electricity and money, while others use innovative technology to allow our larger customers to ease strain on the provincial electricity grid during peak demand periods.

While we're proud of our accomplishments, our main focus is on the challenges facing Ontario's electricity transmission system. Meeting these challenges by constructing the necessary transmission infrastructure will require cooperation with all of our stakeholders.

As guardians of the province's electricity transmission system, we have a number of key investment initiatives that require our utmost attention in the year ahead. Most significant of those initiatives is the proposed construction of a new 500-kV transmission line to deliver additional electricity to southern Ontario. We are undertaking consultations with the public and other interested groups about the routing of the line as well as its benefits and impacts.

We will continue to seek approvals for a number of other major projects which are geared to improving the reliability of supply to local areas within Ontario.

My management team and I will continue to ensure that Hydro One works efficiently, effectively and in the best interests of the people of Ontario. I am enthusiastic about the challenges that lie ahead of us and proud of our record of past achievements.

I'd like to thank Hydro One's employees for working safely and with the utmost commitment to our customers. We rely on the work our employees do every day to make sure that the people of Ontario can put power to work.

Laura Formusa
President and Chief Executive Officer - Acting

Stephanie Oatway, Energy Analyst, CVRD Inco, Sudbury

Power on demand

"Power is useless unless it is there when you need it. That is why reliable transmission is so critical to our business," says Stephanie Oatway, Energy Analyst, CVRD Inco.

When Ontario's largest single-point electricity user speaks, Hydro One listens. Every year Inco's Ontario operations represent about ¾ of 1% of Ontario's total electricity consumption. How much is that? 1,400 Gigawatt hours, enough to power a city the size of Barrie.

While Inco generates about 20% of the electricity that it needs, it depends on the reliability of Hydro One's transmission system to keep it operating safely and profitably. With as many as 2,000 people working as far as two kilometres underground, having a secure, stable source of electricity is a serious matter.

And with today's on-demand supply management systems and the booming nickel market, losing time to electricity failures is unacceptable.

Stephanie Oatway is responsible for making sure Inco has the electricity it needs to produce the 275 million pounds of nickel per year plus copper and other precious metals. As a representative of our largest customer, she is in constant contact with Hydro One to make sure we deliver on our promises.

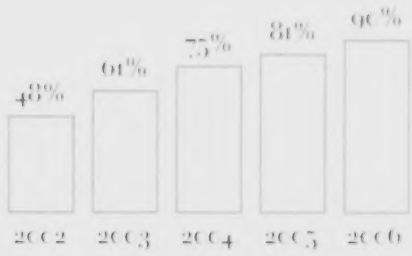
Last year our customers, big and small, told us we were doing better than ever on communicating and meeting our commitments to them.

275

MILLION POUNDS.

the amount of nickel Inco's Sudbury operations produce per year.

Large Industrial Customer Satisfaction



Customer satisfaction continued to climb in 2006, with 86% of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

Transmission reliability is a big reason our customers are more satisfied than ever before. The North American Electric Reliability Council awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's extensive audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

Hydro One's senior management team devotes time and energy to getting to know our Large Customers' businesses. Each member of the senior management team has direct relationships with our customers. They meet on a regular basis and are available any time if a customer has a question or an issue.

"Hydro One's people have taken the time to understand our business and they know what's at stake for us. They get it," Oatway says.

Inco uses 1,400 Gigawatt hours of electricity per year to power its operations – making it Ontario's largest single-point user.

Camp Lau-Ren, Deep River

The buzz of camp

Shortly after dinner on July 17, dark clouds filled the sky over Camp Lau-Ren on the edge of the Ottawa River.

"The winds came right through the camp toppling trees and knocking down power lines. It was a matter of seconds and the power was out," says Nicky Nel, a volunteer counsellor for the last 15 years with Camp Lau-Ren. "We rushed around and made sure everyone was safe and after it was all done our first question was, 'Can camp happen without electricity?'"

The campers at Camp Lau-Ren weren't the only people asking that question.

Across Ontario, 170,000 Hydro One customers lost electricity. With tens of thousands of trees down, more than a thousand power poles broken and hundreds of kilometres of electricity line buried beneath trees snapped like matchsticks, it was the worst damage we'd seen since the 1998 Ice Storm. It would be more than a week until everyone had their power back on.

120 KM/h

winds during three major storms and eight tornadoes pounded Ontario in the summer of 2006.

Hydro One responded to this storm by mobilizing our highly trained workforce, bringing in partners from other utilities and working long days to safely return electricity service to our customers. Our fleet of helicopters filled the sky and crews worked tirelessly to rebuild Ontario's electricity delivery system. In the first 24 hours, we restored electricity to 90,000 of the customers that had been affected.

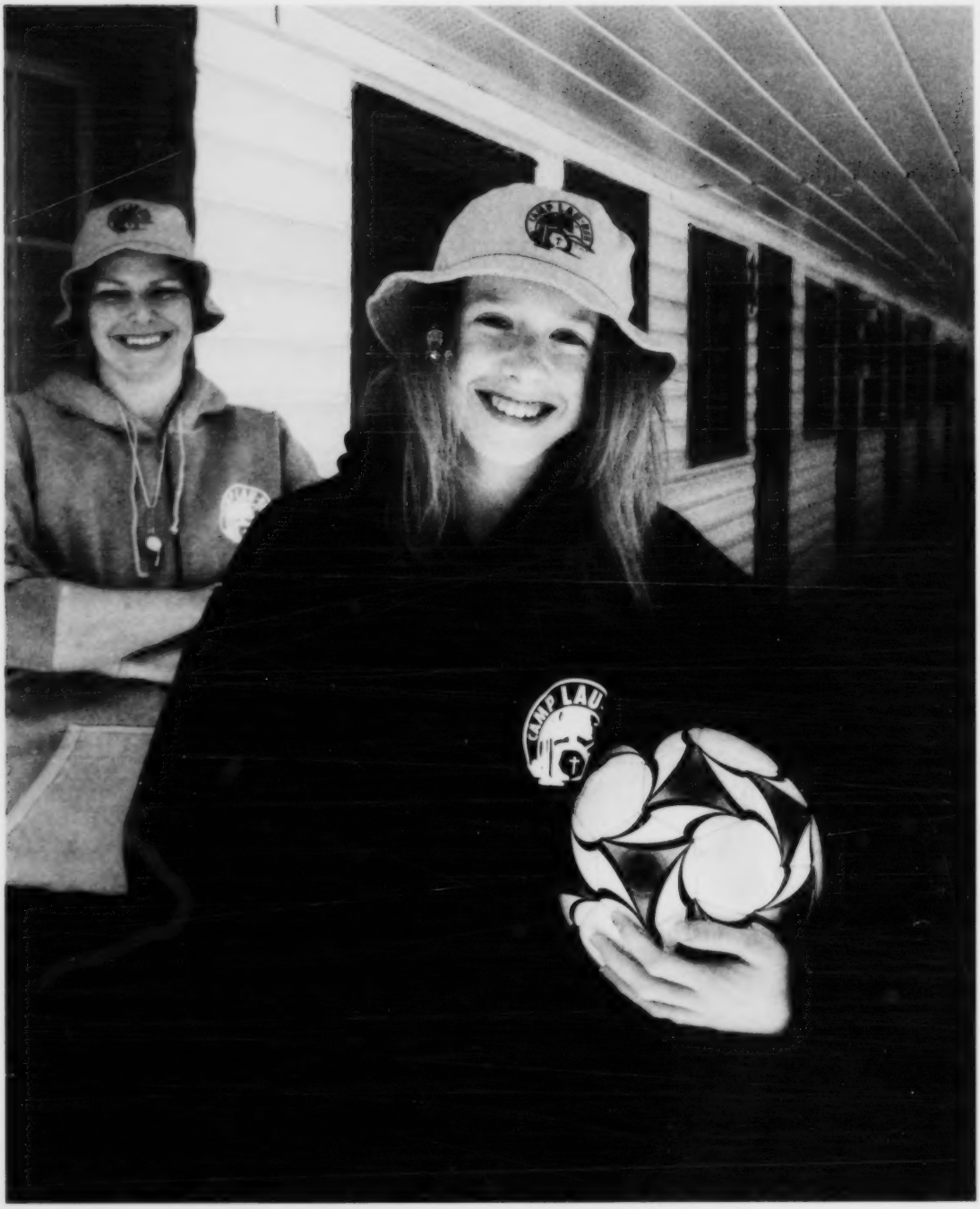
For our work on this storm and two others in a two-month period, the Edison Electric Institute awarded Hydro One the *Emergency Recovery Award*, the first time this honour has been bestowed on a utility based outside of the United States.

While recognition from our peers as one of the best in the business at storm recovery means a lot, it pales in comparison to the way our customers responded. After four days of sharing two outhouses between 60 people, with no electricity, no flush toilets, no electric lights and no running water, Hydro One trucks were treated to a hero's welcome when they finally pulled into Lau-Ren.

"When we saw the trucks, we knew Hydro One had reached us," Nicky says. "The campers were yelling and greeting them with signs. It was a great moment. I think for a lot of the campers, they had a whole new appreciation for electricity."

Storm Recovery

(Percentage of 170,000 affected customers restored)



Hydro One deployed more than 1,000 workers, who worked 16-hour days to restore electricity and repair the worst damage since the 1998 Ice Storm.

Cole Cacciavillani of CF Group Greenhouses, Leamington

Green power blooms

Keeping a greenhouse's climate at the perfect temperature and humidity depends upon electricity. The summer heat inside the greenhouse is so great that without the electric fans, the plants would never survive to bloom. During Ontario's coldest months, without electricity there'd be no flowers for Valentine's Day.

Backup electricity generation for Ontario's greenhouse industry is truly a matter of life and death.

"If we lose power, we're out of business," says Cole Cacciavillani, whose father Floyd started the family business with a single greenhouse in the 1950s.

In the last decade, CF Group Greenhouses (CF Group) has grown enough potted plants to cover Ontario. It's also developed generator technology to help greenhouses and other critical electricity users meet their own urgent power needs.

"All greenhouses invest in backup generation, but we only need it in emergencies. With help from Hydro One, we've connected that generation to the grid to put it to work for the rest of Ontario," says Cacciavillani.

Working with Hydro One, Cacciavillani has connected close to 4 MW of power that Ontario can call on when it needs more supply. The connection contributes to Ontario's supply reliability, takes stress off of Hydro One's transmission system and helps Ontario greenhouses turn a backup system into an asset.

4,000

Number of old, energy-sapping refrigerators, freezers and room air conditioners collected from our customers.

880,000

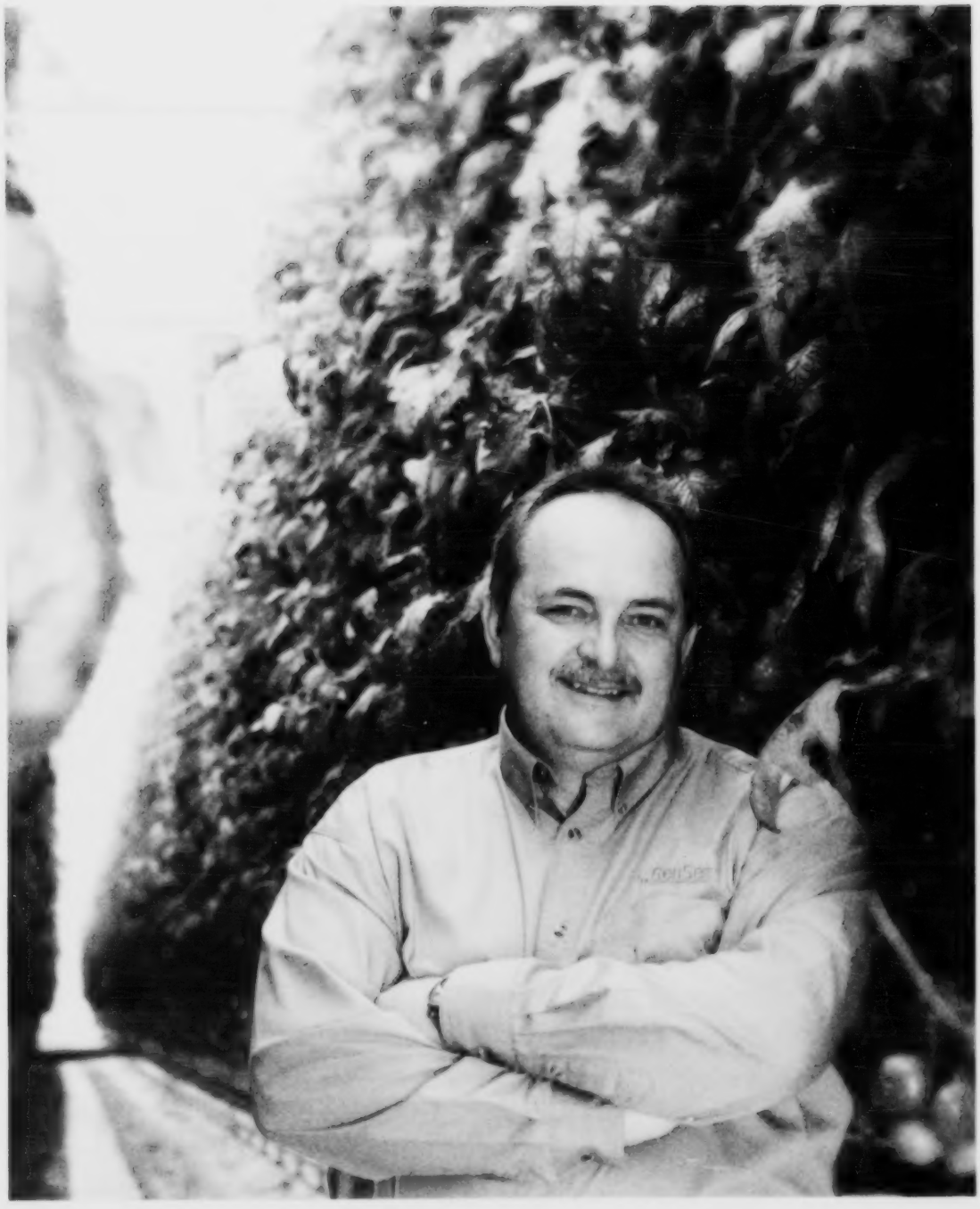
Number of our customers who participated in one of our conservation and demand management programs.

Ontario's greenhouses not only contribute about $2 billion a year to the province's economy, the network of generators managed by the CF Group and connected to Hydro One's grid now contributes about 4 MW of electricity, enough to power 1,300 homes.

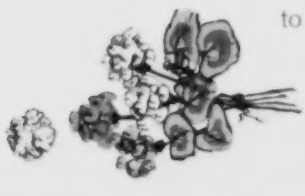
Finding new ways for customers to use electricity wisely is the goal of Hydro One's Conservation and Demand Management group. In 2006, Hydro One not only helped enterprises like greenhouses and wind farms connect to the grid, we worked with our approximately 1.3 million residential customers to reduce peak demand.

Programs like SmartStat, the PowerCost Monitor and Appliance Retirement made a concrete difference to the amount of electricity Hydro One customers used. Our team removed more than 4,000 energy-hogging refrigerators from the grid. Our PowerSaver tour, in conjunction with Home Depot, travelled the province and provided customers with vital information on ways to reduce electricity usage and offered advice on energy efficient products.

By working together and encouraging innovation, Hydro One and Ontario energy users and generators can meet future challenges.



Hydro One helped CF Group Greenhouses connect about + MW of electricity to the grid, enough to power about 1,300 homes in times of short supply.



accomplishments

In 2006, Hydro One completed digging a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative project will carry an array of electricity transmission lines to tie the east and west halves of the city together, with minimal disruption to traffic or residents. Expanding the links between east and west by running new transmission lines through the $45 million investment will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

The project is scheduled for completion late next year with the new 230-kV circuit expected to be operational by early 2008.

Hydro One has signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems.

The $124 million investment for Hydro One will add an important new connection between the two grids. The first phase of the project – the new connection with Ontario – will come into service in early 2009, and will have a capacity of 900 MW. The second phase – the addition of a reinforcement line – will be brought into service in the spring of 2010, and will increase the connection's capacity to 1,250 MW.

Highly Rated

Dominion Bond Rating Service raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. In addition, our short-term debt rating was upgraded to R-1 (middle) from R-1 (low).

Construction crews rebuilt the interconnection in the Sarnia area with the transmission operator in Michigan. This connection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of our existing high-voltage transmission system.

Hydro One is reinforcing the high-voltage transmission system in the Niagara region which will help significantly in meeting electricity needs in Southern Ontario during high-demand periods.

These upgrades will increase power import capacity from New York State up to 800 megawatts – enough power to meet the needs of about 260,000 homes – and accommodate additional power supplied by Ontario Power Generation's Sir Adam Beck stations after completion of a third tunnel at Niagara Falls.

In August, the Kleinburg Training Centre opened its doors to teach Ontario's future electricity workers.

The need for the facility was clear with the number of apprentices needing training doubling from 176 in 2003 to close to 400 in 2006.

This facility allows us to give the next generation of line maintainers, meter readers, distribution technicians, protection and control trainees hands-on experience in a safe environment.

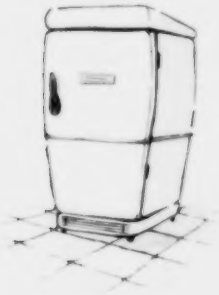
The centre not only provides vital training to Hydro One apprentices, it's a Ministry of Training, Colleges and Universities certified facility. Apprentices from utilities across the province come here to put spurs on for the first time and take those tentative first steps up a wooden pole.

Close to

100

MILLION kWh

enough electricity to power 8,200 homes for one year, were saved by Hydro One's customers through our conservation and demand management programs.



Customers told us the old system for checking outages on our website was cumbersome, so we improved it. Our redesigned online Power Outage Notification system improves communications between Hydro One and the public and provides real-time information to the media during major storms or other outage situations. The new system paints a very accurate picture of the status of our electricity transmission and distribution system.

$807,728

was raised by Hydro One employees for charities of their choice in 2006.

Hydro One Senior Management

Laura Formusa
President and Chief Executive Officer
Acting
Hydro One Inc.

Joe Agostino
General Counsel
Acting

Myles D'Arcey
Senior Vice-president,
Customer Operations

Steve Dotey
Vice-president,
External Relations

John Fraser
Vice-president, Internal Audit
and Chief Risk Officer

Tom Goldie
Senior Vice-president,
Corporate Services

Peter Gregg
Vice-president,
Corporate and Regulatory Affairs
and Executive Office

Rick Kellestine
Vice-president,
Culture

Naim McQueen
Vice-president,
Engineering and
Construction Services

Geoff Ogram
Vice-president,
Asset Management

Wayne Smith
Vice-president,
Grid Operations

Beth Summers
Chief Financial Officer

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2006 and 2005.

Overview

We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2006, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

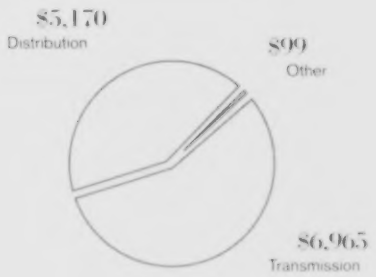
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2006, we earned total transmission revenues of $1,245 million primarily by transmitting approximately 151 TWh of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest segment, representing approximately 60% of our total assets.

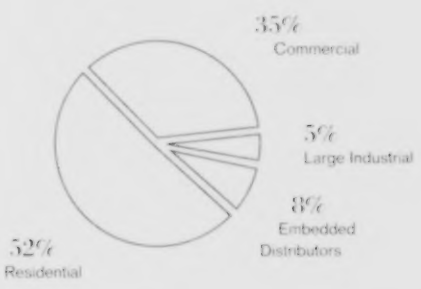
Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 48 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, over half of our distribution revenues are earned from our residential customers.

Total Assets
December 31, 2006
(Cdn $ millions)



2006 Distribution Revenues



Other

Our other business segment contributed revenues of $27 million in 2006 and has assets of about $99 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2006, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

— *Safety*: Create and maintain an injury-free workplace with a concentrated focus on elimination of serious injury and "near misses" in high potential harm categories of work.

— *Customers*: Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.

— *Reliability*: Enhance the reliability of our transmission and distribution systems. In transmission, we have assumed a proactive leadership role in developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.

— *Financial*: Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.

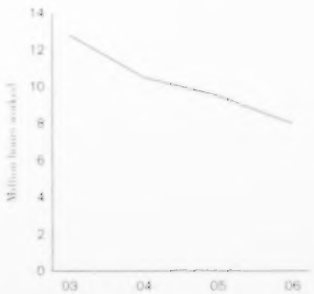
— *Employees*: Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

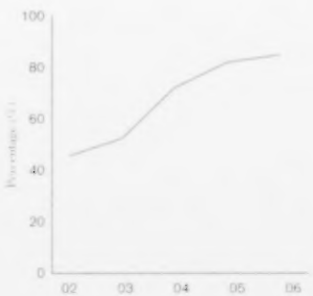
We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We substantially met or exceeded our challenging 2006 objectives, improving in a number of areas over 2005, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to achieve a record of no serious injuries and no serious near misses. Accordingly, we measure our high Maximum Reasonable Potential for Harm (MRPH) incidents rate to identify possible problems or situations that may increase the risk of injury. As shown in the accompanying chart, we had eight high MRPH incidents per million hours worked in 2006, which is 16% lower than 2005, 24% lower than 2004, and 38% lower than 2003.

High MRPHs



Large Transmission Customer Satisfaction



We also maintain our focus on serious incidents in high risk areas including electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. The number of serious incidents declined from about nine incidents per million hours worked in 2003, to approximately five in 2006. Going forward, we will continue to stress the importance of safety through a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments, development of a learning management system and further use of decision analysis tools to reduce human error and its consequences.

Customer satisfaction is also vital to our success. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 83% to 86% satisfied as compared to 2005. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our Residential and Small Business Customers and survey results show an increase in the level of satisfaction to 85% satisfied from 81% last year. While our 2006 Generator satisfaction level of 74% was acceptable, it was slightly below our annual target, and addressing the concerns identified will be an area of focus in 2007. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Weather patterns and generation constraints require exemplary performance from both our transmission and our distribution systems. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2006, we met our annual reliability targets and achieved some improvements over 2005. We did so while managing the impacts of a number of devastating storms throughout the year, including the back-to-back storms experienced over the summer. We enhanced our storm response and communication, including improving processes, improving our website and providing "real time" information through emails and faxes. Subsequent to year end, the Edison Electric Institute (EEI) honoured us with an emergency recovery award for our outstanding efforts to restore electricity service during these storms. This is the first time this prestigious award has been won by a utility outside of the U.S.

Meeting our shareholder requirements is an integral part of our business focus. Strong financial performance was again characterized by our 2006 results and we maintained or improved credit ratings on both our short-term and long-term debt. On June 23, 2006, Dominion Bond Rating Service Inc. raised our short-term debt rating to R-1 (middle) and our long-term debt rating to A (high), as a result of key factors including their expectation that our financial profile will remain strong over the medium to long term.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). The OEB sets prices at least every 12 months, or more frequently, and may upon review, reset prices over the next 12 months to better reflect the cost of supply. The OEB currently plans to review the need to reset prices every six months. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and to assist with the stability of rates for RPP customers, among others. As part of its mandate to ensure the adequate long-term supply of electricity, and consistent with the Province's direction regarding supply mix, the OPA is in the process of developing the Integrated Power System Plan (IPSP), which must be submitted for review and approval to the OEB which will conduct public hearings and consultation. The OPA currently expects to submit the IPSP to the OEB in March 2007. As part of the IPSP process, the OPA has issued a number of discussion papers for comment by stakeholders. Of the papers issued to date, two are most important to the transmission business and influence our capital expenditures; "Discussion Paper 5 – Transmission" and "Discussion Paper 7: Integrating the Elements – A Preliminary Plan" (See "Future Capital Expenditures" on page 29).

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination will further initiatives undertaken by individual local distribution companies (LDCs), including our distribution business, as a result of distribution rate increases approved in 2005. Some of the funds associated with this increase were required to be used on CDM programs. Our programs amounted to approximately $43 million over the period 2005 to 2007, consistent with this direction. The overall goal of the CDM programs is to reduce provincial demand by 6,300 MW by 2025. The OPA issued "Discussion Paper 3 – Conservation & Demand Management" and is expected to submit a CDM plan as part of the IPSP.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely and providing customers with access to information about their consumption. A new entity will oversee the communications systems and technologies, collect and manage data, and facilitate meter procurement. LDCs, including our distribution businesses, will own, install, operate and maintain their own meters. We are currently deploying smart meters under our program (See "Future Capital Expenditures" on page 29).

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. In 2000, the OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks), seeking approval of a revenue requirement of $1,263 million for 2007 and $1,298 million for 2008, subject to minor updates in the normal course. This application is based on achieving a 10.5% return on equity and an increase in the common equity component of the capital structure from 36% to 40%. The proposed rate increases are 4.3% in 2007 and 2.7% in 2008, with the impact on an average customer's total bill estimated to be less than 0.5% in both years. Consistent with the OPA discussion papers, the application includes funding to enable new generation and ensure the adequacy of area supply, as well as the continued reliability of aging transmission assets. We believe the proposed regulated return, in conjunction with capital structure, supports the financial metrics underlying an A credit rating category, facilitating access to capital markets at reasonable rates.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue decreased by approximately $13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates were initially approved by the OEB in 2000 to provide for cost recovery and a return on deemed common equity targeted to be 9.88%. Related distribution rate increases were phased in over a number of years, with the final installment approved by the OEB in March 2005. In August 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. On April 12, 2006, the OEB announced its decisions regarding this application and that of our distribution business conducted by Hydro One Brampton Networks Inc. (Hydro One Brampton). On the basis of the written and oral evidence submitted, the OEB approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

While current distribution rates are based on a cost of service rate regulation model, the OEB is in the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007–2010. Consistent with OEB guidelines, we plan to apply for distribution rate adjustments in February 2007, with minimal impact anticipated on the total customer bill. This application is based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management.

On March 21, 2006, the OEB approved a monthly rate of 30 cents per residential customer, effective May 1, 2006, as initial funding for the required investment in smart meters. The distribution rate application, to be filed with the OEB in February 2007, will include a request to increase this level of smart meter funding. Expenditures in excess of recoveries are currently being recorded as a regulatory asset, with disposition to be established at a later date.

Results of Operations

Revenues

Year ended December 31

(Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	1,245	1,310	(65)	(5)
Distribution	3,273	3,085	188	6
Other	27	21	6	29
	4,545	4,416	129	3
Average annual Ontario 60-minute peak demand (MW)[1]	22,650	23,074	(424)	(2)
Distribution – units distributed to customers (TWh)[1]	29.0	29.7	(0.7)	(2)

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Transmission revenues decreased by $65 million, or 5% in 2006, compared to last year, reflecting two recent OEB decisions. On February 21, 2006, the OEB applied an earnings sharing mechanism to any transmission earnings in excess of our approved rate of return of 9.88% for the period January 1, 2006 until new rates are set. Consequently, 50% of excess earnings recovered from customers are deferred as a regulatory liability. This decision had the effect of reducing transmission revenues by $33 million for the year. On December 8, 2005, the OEB adjusted revenue allocation factors for all of the Province's electricity transmitters, reducing 2006 transmission revenues by $13 million.

In addition, 2006 monthly peak demands were generally lower than last year. While there were a few exceptions, notably the all-time record peak demand of 27,005 MW set on August 1 and the May record peak demand of 24,857 MW, our average annual Ontario 60-minute peak demand was 424 MW lower and the overall related load was 5,083 MW lower than last year, resulting in lower revenues of $26 million. The impact of these reductions was partially offset by a marginal increase in ancillary revenues related to revenues earned from the secondary use of our land rights-of-way.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by our distribution rates, the amount of electricity we distribute and the cost of purchased power. Distribution revenues also include minor ancillary services revenues, such as rental fees charged to telecommunications and cable television companies for the use of our poles, and miscellaneous charges such as those made for late payments.

Distribution revenues increased by $188 million, or 6%, in 2006 compared to last year, primarily as a result of two OEB-approved distribution tariff rate increases that became effective April 1, 2005 and May 1, 2006. The April 1, 2005 increase was originally scheduled to be effective March 1, 2003, and was subsequently suspended for all LDCs by the *Electricity Pricing Conservation and Supply Act, 2002*. On April 12, 2006, after reviewing our evidence, the OEB approved increases in distribution tariff rates for our distribution businesses conducted by Hydro One Networks and Hydro One Brampton, effective on May 1, 2006. We also received OEB approval for low-voltage rates for services provided to LDCs that are embedded within our service territory. These tariff rate increases support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, and resulted in higher distribution revenues of $105 million compared to last year.

Distribution revenues also include the recovery of increased purchased power costs of $92 million, as described below under "Purchased Power." The impact of the increases in tariff rates and purchased power costs was partially offset by lower distribution tariff revenues of $5 million associated with lower demand, as well as marginally lower ancillary revenues.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory. These costs consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. From April 1, 2004 to March 31, 2005, for certain low-volume and designated customers, the commodity price of electricity was based on an interim two-tiered pricing structure. This structure was subsequently replaced by the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP continue to pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the interim pricing plan and RPP affecting the two-year period 2005 and 2006 is provided below.

Summary of Interim Pricing Plan & RPP

		Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Price Plan	Effective Date	Residential	Non-Residential	First Tier	Second Tier
Interim	April 1, 2004	750	750	4.7	5.5
RPP	April 1, 2005	750	750	5.0	5.8
RPP	November 1, 2005	1,000	750	5.0	5.8
RPP	May 1, 2006	600	750	5.8	6.7
RPP	November 1, 2006	1,000	750	5.5	6.4

Purchased power costs increased in 2006 by $90 million, or 4%, to $2,221 million compared to last year. Our increased purchased power costs were primarily due to higher costs of $189 million associated with the OEB's RPP for residential and other eligible customers, combined with the 2005 impact of providing the *Ontario Price Credit* to RPP customers in accordance with a regulation issued in October 2005. This $140 million credit was provided to RPP customers in 2005 to recognize a lower cost of power than the fixed commodity price for the period April 1, 2004 to March 31, 2005. These increases were partially offset by lower wholesale commodity prices of $137 million for customers who are not eligible for the RPP, and lower wholesale market service charges levied by the IESO of $55 million. The remaining $47 million reduction was due to a lower demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31

(Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	390	353	37	10
Distribution	460	413	47	11
Other	30	26	4	15
	880	792	88	11

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $37 million, or 10%, in 2006 compared to last year. Within our work programs, we continued to make the investments necessary to ensure the safe and reliable operation of our installed transmission system, with particular focus on the assets that are critical to generation and to the unrestricted supply of electricity to our customers. We experienced increased work program requirements of approximately $32 million this year, primarily related to increased station maintenance expenditures, including our focus on our 750 MVA autotransformers, higher employee benefit costs attributable to a lower discount rate for actuarially determined benefit costs, economic increases in materials and fuel costs and the impact of a labour disruption in 2005. Other support costs increased marginally by $5 million in 2006 compared to the previous year. Higher information technology requirements this year, combined with the impact of last year's recoveries associated with insurance settlements and bad debt recoveries, were substantially offset by this year's cost reduction associated with a negotiated property tax settlement.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $47 million, or 11%, compared to last year. We experienced increased work program requirements of approximately $50 million, primarily within our lines and customer care work programs. These increases reflect our recovery efforts following a series of destructive storms, particularly in the third quarter. In 2006, we experienced 10 significant storm events, compared to 4 in 2005. Consequently, our storm-related repair and maintenance expenditures for our distribution business increased by approximately $13 million to $21 million. In addition, our annual work program expenditures were impacted by higher fuel costs, the same economic increases that we experienced within our transmission business, and the effects of last year's labour disruption. Other costs incurred to support our distribution work programs declined by about $3 million, primarily as a result of our reassignment of resources to support our larger capital program this year, partially offset by the impact of higher information technology requirements.

Depreciation and Amortization

Depreciation and amortization expense increased by $28 million, or 6%, to $515 million this year. Depreciation expense was higher by $10 million relative to 2005, primarily as a result of the placement of new assets in service, consistent with our ongoing capital work program. Year-over-year, amortization of regulatory and other assets increased by $18 million. This increase was attributable to increased amortization of our regulatory assets as a result of the OEB's April 12, 2006 decision to approve recovery of certain regulatory assets.

Financing Charges

Financing charges declined by $30 million, or 9%, to $295 million compared to last year. Approximately $25 million of this decrease was due to a lower average effective interest rate on our outstanding long-term debt. In addition, we capitalized approximately $5 million more interest this year, primarily as a result of a higher level of capital expenditures.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes declined by $19 million, or 10%, to $179 million in 2006 compared to 2005. Approximately $17 million of this reduction was due to this year's lower taxable income. The tax benefit of approximately $30 million that was recognized in the first quarter of 2006 pertaining to the recovery of prior years' corporate income taxes, was partially offset by the impact of last year's second quarter tax benefit in the amount of $21 million, which pertained to prior period tax losses of one of our subsidiaries. Payments in lieu of corporate income taxes were also reduced by tax changes enacted in the second quarter of 2006 relating to the elimination of the federal large corporations tax and higher capital cost allowance rates. These impacts were partially offset by taxes payable on transmission amounts received but not recognized for accounting purposes, primarily due to the OEB's earnings sharing mechanism.

Net Income

Net income of $455 million was lower by $28 million, or 6%, compared to 2005 results. Our net income for the year reflects higher expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, combined with lower transmission tariff revenues resulting from lower demand and the effects of the OEB's earnings sharing mechanism. The impact of these factors was partially offset by higher distribution tariff revenues associated with OEB-approved tariff rate increases and a marginal reduction in our effective tax rate. This tax rate reduction primarily resulted from the relative sizes of the tax benefits recognized in the first quarter of 2006 and in the second quarter of 2005.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2005 through December 31, 2006. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2006				2005			
Quarter ended	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues	1,142	1,165	1,078	1,160	1,025	1,179	1,018	1,194
Net income[1]	101	103	99	152	104	133	115	131
Net income to common shareholder[1]	96	99	94	148	99	129	110	127

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31

(Canadian dollars in millions)	2006	2005
Operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Investing activities		
Capital expenditures	(823)	(691)
Other financing and investing activities	11	1
Net change in cash and cash equivalents	(20)	–

Operating Activities

Net cash from operating activities decreased by $273 million to $896 million, compared to 2005 results. This reduction primarily reflects the impact on our working capital requirements of providing RPP customers with the $140 million *Ontario Price Credit* early in 2006, funding for which was received by us from the IESO in late 2005. Our working capital requirements were also impacted by higher electricity prices charged to RPP customers in 2006, changes in the timing of tax payments and changes in trade accounts payable balances related to our work programs.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures in August 2007 and which has a two-year extension option. As at December 31, 2006, we had $60 million in short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2006, we had $5,270 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $1,725 million is remaining and is currently available until July 2007.

During 2006, Dominion Bond Rating Service Inc. raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. Our short-term debt rating was upgraded to R-1 (middle) from R-1 (low). Our credit ratings are:

	Rating	
Rating Agency	Short-term Debt	Long-term Debt
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	A3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2006, we issued $775 million in long-term debt under our medium-term note program and we repaid $589 million in maturing long-term debt. In comparison, during 2005 we issued $500 million in debt under our medium-term note program and we repaid $648 million in maturing long-term debt. In 2006, we increased our short-term notes by $60 million compared to a reduction of $40 million in 2005.

In 2006, we paid dividends to the Province in the amount of $350 million, consisting of $332 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $273 million and preferred dividends of $18 million. In 2006, cash dividends per common share were $3.320 compared to $2.730 per common share in 2005. Cash dividends per preferred share were $1.375 in both 2006 and 2005.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations, the level of net income and timing. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31

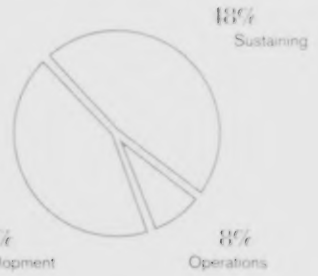
Canadian dollars in millions	2006	2005	$ Change	% Change
Transmission	402	349	53	15
Distribution	417	338	79	23
Other	4	4	–	–
	823	691	132	19

Transmission

Transmission capital expenditures increased by $53 million in 2006 to $402 million, compared to 2005. Expenditures to expand and reinforce the transmission system were $179 million, $54 million higher than last year. These increased development investments primarily reflect higher required generation and load customer connection expenditures in this year. Our generation-related expenditures included a major reconfiguration of our Lambton Transformer Station, to enable the connection of new gas-fired generation. Increased load customer connection work included construction of a new transformer station to accommodate growth in Simcoe Region and work on transformer station improvements in Durham Region. Our development expenditures also included two critical projects to improve the flow of electricity in recognition of growing needs: the Niagara Reinforcement Project, which will reinforce the transmission system in the Niagara region and provide access to new sources of generation; and our Downtown Toronto Cable Project, which involves the construction of two underground cable circuits to reinforce our electricity transmission facilities. Our Niagara Reinforcement Project is essentially complete. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area and discussions continue between the affected aboriginal peoples and the various government entities involved. Once we regain access and perform a site condition assessment, we expect project completion within six weeks. In 2005, we substantially completed construction of the Parkway Transformer Station and refurbishment of the Cooksville Transformer Station. Both projects were carried out to accommodate the closure of the Lakeview Generating Station.

Our expenditures to sustain the existing transmission system were $192 million, representing a marginal decrease of $1 million compared to last year. Additional sustainment expenditures were made to replace storm-damaged equipment and to purchase new transformers. The impact of these requirements, together with the impact of last year's labour disruption, were substantially offset by reduced engineering and construction expenditures related to the refurbishment and replacement of end-of-life lines, stations and telecommunications assets. Other transmission capital expenditures were $31 million, unchanged from last year.

2006 Transmission Capital Expenditures

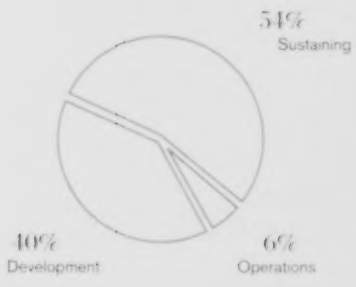


Distribution

Distribution capital expenditures increased by $79 million to $417 million in 2006, compared to the prior year. Expenditures to sustain our low-voltage distribution system were $225 million, an increase of $63 million over 2005. This increase was primarily a result of higher storm-related expenditures to replace damaged assets. Year-over-year capital expenditures for storm restoration were $62 million, an increase of $36 million. As a result of the significant storm activity this year, we replaced more than 1,600 distribution poles and more than 200 kilometres of line. Increased sustainment expenditures also reflect higher planned replacements of end-of-life assets, unplanned asset replacements and line relocations, as well as the impact of last year's labour disruption.

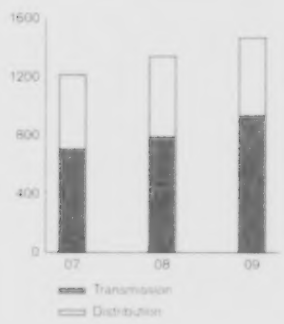
Capital expenditures to expand and reinforce our distribution network were $167 million, an increase of $20 million compared to last year. This increase primarily reflects our deployment of smart meters during the year. Our other distribution capital expenditures decreased by $4 million to $25 million.

2006 Distribution Capital Expenditures



Future Capital Expenditures

(Cdn $ millions)



Future Capital Expenditures

Our capital expenditures in 2007 are budgeted at about $1.25 billion, an increase of over $400 million from 2006 levels. The 2007 capital budgets for our transmission and distribution businesses are about $700 million and $500 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately $1.35 billion in 2008 and $1.5 billion in 2009, primarily reflecting increasing investments in necessary transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with the OPA's discussion papers and the needs of our aging transmission system under continued challenging conditions of tight generation supply. These investments will facilitate an adequate and reliable supply of electricity in the public interest. The investment levels also reflect the mass deployment of smart meters within our distribution businesses beginning in 2007. The replacement of critical information technology systems is also contemplated. Capital expenditures of our other business segment are budgeted at about $20 million in 2007, largely due to the implementation of a dedicated optical network to provide secure, high capacity connectivity across numerous health care locations in Ontario.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2007 to 2009, amounting to almost $2.4 billion. Our investment plan will address new development and supply enhancement initiatives, including system expansion, generation requirements and load connections. The transmission program also continues the focus on "mission critical" assets, which are those assets critical to generation facilities and the unrestricted transmission of energy to our customers.

The development component of our investment plan for transmission includes enhancements to the transmission system in the Bruce Peninsula to accommodate new wind generation and redeveloped nuclear generation; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Midtown Toronto; and a new interconnection between Ontario and Quebec. Initiatives taken by the Province and the OPA have led to many new generation developments and we are undertaking investments to connect many of these to the transmission system. Major connections include large new gas generators in Sarnia, the west GTA and downtown Toronto, and several large new wind farms. Several projects have need dates that cannot be met if approvals are delayed beyond the release of the IPSP. As such, we have initiated the processes required to file Leave-to-Construct applications with the OEB and to receive other approvals as required.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Investments in mission critical assets ensure a reliable supply of energy throughout the province. Through targeted replacement programs for components such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continues to be essential. Examples of projects initiated to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston and Red Lake. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems will lead to improved reliability.

The timing of many development projects is uncertain as they are dependent upon the final IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Consistent with our approved 2006 distribution rate applications, capital expenditures for the period 2007 to 2009 are budgeted at approximately $1.7 billion. This amount includes core development and sustainment work as well as our smart meter program. Our core work will focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. Given initiatives to encourage renewable energy technologies, we also anticipate increased connection of new generators which could trigger the need for larger system modifications.

Our distribution investment plan includes the mass rollout of the smart meter program. Over the period 2007 to 2010, we anticipate installing over 1 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program and install 240,000 meters. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2006

(Canadian dollars in millions)	Total	2007	2008/2009	2010/2011	After 2011
Contractual obligations (due by year)					
Short-term note payable	60	60	–	–	–
Long-term debt – principal repayments	5,270	395	900	650	3,325
Long-term debt – interest payments	4,769	291	524	448	3,506
Inergi LP (Inergi) outsourcing agreement[1]	496	110	192	178	16
Operating lease commitments	16	5	9	1	1
Total contractual obligations	10,611	861	1,625	1,277	6,848
Other commercial commitments (by year of expiry)					
Bank line[2]	750	750	–	–	–
Letters of credit[3]	118	118	–	–	–
Guarantees[3]	275	275	–	–	–
Pension[4]	8	8	–	–	–
Total other commercial commitments	1,151	1,151	–	–	–

[1] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2007, with a two-year extension option.

[3] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $22 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one month in arrears. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or within our capital expenditures. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our payments in lieu of corporate income taxes, which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province of Ontario

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence major business and corporate decisions. Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve potential conflicts with the Province on terms satisfactory to us.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rates of return.

On September 12, 2006, Hydro One Networks filed, with the OEB, its application and evidence in support of its 2007 and 2008 transmission revenue requirements based on a capital structure with a higher equity component and a higher return on equity. Our operation, maintenance and administration expense levels have increased over time and our transmission business rate base has increased, reflecting prudent expenditures, since transmission rates were initially established. However, there is the risk that these increases may be disallowed by the OEB. Any disallowed capital expenditures would be charged to the results of operations in the period that the OEB renders its decision. Insufficient funding for our transmission business could adversely impact our financial results and the operating performance of the transmission system.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2007, which could significantly reduce our revenues, particularly transmission. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transmission facilities by constructing their own assets under certain conditions.

There is also a risk we could be required to invest in large-scale transmission infrastructure projects, to incur unexpected capital expenditures to maintain or improve our assets, and to connect new third-party generation assets. The Province has passed regulations authorizing us to procure smart meters but we are only currently authorized to recover 30 cents of the associated costs in rates. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential charges to our results of operations.

Asset Condition

We continually maintain our assets to provide reliable service and to accommodate customer needs. However, our installed asset base is aging to the point where the assets require increased maintenance, major refurbishment or replacement. Executing these activities is also becoming more challenging as the opportunities to remove equipment from service to accommodate work are becoming increasingly limited. Consequently, we may not be able to complete the necessary repairs and replacements on a cost-effective or timely basis, which could affect transmission reliability and our ability to deliver sufficient electricity.

Risk Associated with Transmission Projects

Significant investments are needed to increase transmission capacity and enable the delivery of reliable electricity from existing and new generation sources to Ontario consumers. These investments are, in most cases, subject to OEB approvals, which can include expropriation, and where required, environmental approvals and consultation and possibly accommodation with First Nations. The ability to make such investments may also be impacted by public opposition. If we are unable to make these necessary investments, the reliability of our transmission system and our ability to deliver sufficient electricity could be materially adversely affected.

Work Force Demographic Risk

Approximately 25% of our employees will be eligible for retirement by 2008. We expect the skilled labour market for our industry to remain highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union or the Society of Energy Professionals. Existing collective agreements with the Power Workers' Union and the Society of Energy Professionals expire on March 31, 2008. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our balance sheet. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to withstand such occurrences, our facilities may not do so in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2007 and 2010. We also plan to incur total capital expenditures of approximately $1.25 billion in 2007 and $1.35 billion in 2008. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and our future capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The next valuation will be prepared as at December 31, 2006 and must be filed on or before September 30, 2007. The required level of contributions effective January 1, 2007 will depend on future investment returns, changes in benefits, and changes in actuarial assumptions. Based on current factors, we estimate annual pension contributions for 2007 and beyond to be up to $100 million per annum. Pension costs are subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $850,000 per year that we are currently paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have an adverse effect on our results of operations if we are unable to recover them in future rate orders.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors in conjunction with the operation our systems may increase safety or environmental risks.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, capture data and produce timely and accurate information used in our business. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing our operating costs, in 2002 we entered into an outsourcing services agreement with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have an adverse effect on our results of operations.

Market and Credit Risk

Market risk refers primarily to risk of loss related to changes in commodity prices, foreign exchange and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2007 and 2008 would have an impact on net income of approximately $2 million and $4 million, respectively. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of $40 million and an insignificant fair value.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2006 amounted to $311 million and principally relate to the regulatory asset recovery accounts (RARAs), employee future benefits other than pension, environmental costs, and expenditures associated with the smart meter program. We have also recorded regulatory liabilities amounting to $473 million as at December 31, 2006. These amounts pertain primarily to pension, export and wheeling fees, and the transmission earnings sharing mechanism. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARAs, or if future OEB direction is judged to be probable. Most of our regulatory assets have been reviewed by the OEB and confirmed as recoverable.

To date, our smart meter expenditures and recoveries have been recorded in regulatory asset accounts consistent with OEB guidance. The timing and amount of inclusion of these amounts in our Statement of Operations is currently uncertain and will depend on future OEB decisions as well as other factors.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related assets for the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our demerger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing the work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of 2% has been used to express current cost estimates as future expenditures. These expenditure amounts have been discounted using a factor of 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or whenever significant changes in regulation occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2006.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2006 increased by 0.25% from those at December 31, 2005 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $13 million per year.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2006 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over a five-year transitional period. The AcSB published an updated detailed implementation plan for achieving convergence in June 2006. The plan calls for the first year of reporting under IFRS to be 2011. At that point, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we began our transition preparations in 2006.

Accounting for Rate-Regulated Operations

Following the approval of its new strategic plan to adopt IFRS, the AcSB revisited the scope of its project on rate-regulated accounting in recognition of the fact that that IFRS does not currently provide any special accounting treatment for rate-regulated enterprises. As a result, the AcSB is expected to issue an exposure draft in early 2007 to propose removal of all specific references to rate-regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). It is expected that the AcSB will allow qualifying enterprises to apply the relevant U.S. accounting standard, Statement of Financial Accounting Standard 71 *Accounting for the Effects of Certain Types of Rate Regulation* (SFAS 71). Enterprises subject to rate regulation will be qualified to use SFAS 71 as long as they meet the specific criteria found in that accounting standard and as long as they apply it in the manner the U.S. standard setter intended. We believe our company meets these criteria. The future application of SFAS 71 will have an impact on our financial statements. Accrual accounting practices will be followed for payments in lieu of corporate taxes, which are currently accounted for on a cash basis as a result of specific OEB direction. The difference between the accrual and cash basis will be reflected through the recognition of additional regulatory assets and, consequently, the impact on our results of operations is expected to be minimal.

Financial Instruments

In 2005, the CICA issued new accounting standards comprising Handbook Section 3855, *Financial Instruments Recognition and Measurement*; Section 3865, *Hedges and* Section 1530, *Comprehensive Income*, all of which become effective for us on January 1, 2007.

The standards require that all financial assets, including derivatives, be carried at fair value on the balance sheet, with the exception of loans, receivables and investments classified as held to maturity, which will be measured at amortized cost. Similarly, all derivative financial liabilities will be measured at fair value on the balance sheet. Other financial liabilities will be measured at amortized cost.

The standards also revise the existing accounting requirements for hedges and establish guidance for reporting comprehensive income, which includes net income and other comprehensive income. Any hedge ineffectiveness will be recognized immediately in the results of operations. Any changes in the fair value of cash flow hedging instruments, to the extent effective, will be recorded in other comprehensive income until the asset or liability being hedged affects the Statement of Operations, at which time the related change in fair value of the derivative will also be recorded in the Statement of Operations. Unrealized gains and losses on changes in the fair value of cash flow hedging instruments will be recorded as other comprehensive income until recognized in the Statement of Operations. This would include any remaining balance of deferred gain or loss on a cash flow hedge that was discontinued prior to the transition date.

Given the nature of our financial instruments and borrowing programs, we do not believe that the transitional impact of the new accounting standards will have a material financial impact on our company.

Accounting for Pension and Other Post-Retirement Costs

In October 2006, the AcSB commenced a project that is expected to result in a requirement to include the funded status (the difference between the plan assets and obligations) of an entity's post-retirement benefit plans on the balance sheet and to recognize changes in the funded status in comprehensive income in the year in which the changes occur. Current Canadian GAAP only requires disclosure of the funded status in the notes to the financial statements. The project will affect disclosures relating to our pension plan, supplementary pension plan, other post-employment and other post-retirement benefits. In addition, the proposals are expected to have a significant adverse impact on our financial ratios. The proposals, however, are not expected to impact our credit rating. The AcSB expects to publish the exposure draft for public comment in the first quarter of 2007 and it is expected to be effective for our company on December 31, 2007. This timing is expected to allow sufficient time to assess the effects on financial metrics referred to in existing contractual arrangements, including debt covenants.

Disclosure Controls and Internal Controls Over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. During 2005, we designed and evaluated the effectiveness of our disclosure control procedures. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that these disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

During 2006 we completed our documentation, evaluation and remediation of internal controls over financial reporting. Our documentation includes flowcharts of key processes, risk matrices, and overviews of test results and remediation activities. The majority of findings related to the evidencing of controls and all remediation was completed during the period. Our focus for 2007 will be the ongoing sustainment of our control environment including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2006, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the presentation of financial statements for external purposes in accordance with GAAP. Our Certifying Officers have evaluated the effectiveness of our disclosure controls and procedures and have found them to be effective.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our top strategic priorities relating to safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our long-term customer satisfaction and safety targets, while we maintain our strong financial profile and reliability performance. In addition, the North American Electric Reliability Council gave our transmission operating facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The EEI has also honoured us with an emergency recovery award, recognizing the outstanding efforts of our staff in restoring electricity service this summer after the significant damage caused by successive storms.

With the approval and implementation of the 2006 distribution rate increase, we are reasonably well positioned to address current distribution work program requirements and to earn the regulated rate of return. This will allow us to further the forestry program and continue initiatives to improve reliability and customer service. We continue to face challenges with regard to funding for our smart meter program. We expect to address some of the shortfall in our February 2007 application and anticipate full funding to be achieved over time.

We remain committed to a prudent and measured approach to distribution rationalization. The Province plans to lift the moratorium on the purchase and sale of electricity distribution assets by Hydro One, with the understanding that any future asset purchases or dispositions help further overall provincial policy interests in the sector. We plan to respond to opportunities, on a voluntary and commercial basis, where they are consistent with strategy. The investment plan does not include any funding for LDC acquisitions or divestitures. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of mission critical assets to ensure the system's continued reliability. Our transmission investment plan supports the achievement of supply mix goals, facilitates the development and use of renewable energy resources, promotes system efficiency and congestion reduction, and facilitates the integration of new supply. The OPA has presented the needs and options for reinforcing and expanding Ontario's transmission system, and discussed the specific transmission initiatives forming the basis of the preliminary IPSP. Significant investments in transmission will be required over the 20-year planning horizon of the IPSP, which is expected to be submitted by the OPA to the OEB in March 2007. In September, we filed a transmission cost of service rate application with the OEB that includes the funding required for this necessary transmission infrastructure, which is vital to the Ontario economy. Given the issued schedule, a decision on our rate application is anticipated late in 2007. Our outlook is premised on the successful outcome of this application.

Our investment plan does not include spending for large-scale investments, such as the expansion of the east-west transmission grid. Funding for required infrastructure to accommodate Bruce Peninsula supply continues beyond the planning period to 2011. Completion of the Toronto third supply option, which is expected to cost in the order of $400 million, also extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and, as such, to maintain reliability.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

Forward-Looking Statements and Information

Our oral and written public communications, including this Management's Discussion and Analysis (MD&A), often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

— the content of the final IPSP, as approved by the OEB;

— delays or denials of the requisite approvals for planned future capital expenditures;

— regulatory decisions regarding our revenue requirements and tariff rates;

— significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and

— future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this Management's Discussion and Analysis. You should review the section entitled "Risk Management and Risk Factors" in detail.

This Management's Discussion and Analysis is dated as at February 14, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2007.

In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 45, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer (Acting)

Beth Summers
Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2006 and December 31, 2005, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Toronto, Canada
February 14, 2007

Consolidated Statements of Operations

Year ended December 31

(Canadian dollars in millions)	2006	2005
Revenues		
Transmission *(Notes 8 and 14)*	1,245	1,310
Distribution *(Notes 3 and 14)*	3,273	3,085
Other	27	21
	4,545	4,416
Costs		
Purchased power *(Notes 3 and 14)*	2,221	2,131
Operation, maintenance and administration	880	792
Depreciation and amortization *(Note 4)*	515	487
	3,616	3,410
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006
Financing charges *(Note 5)*	295	325
Income before provision for payments in lieu of corporate income taxes	634	681
Provision for payments in lieu of corporate income taxes *(Notes 6 and 14)*	179	198
Net income	455	483
Basic and fully diluted earnings per common share (Canadian dollars) *(Note 13)*	4.366	4.652

Consolidated Statements of Retained Earnings

Year ended December 31

(Canadian dollars in millions)	2006	2005
Retained earnings, January 1	1,079	887
Net income	455	483
Dividends *(Note 13)*	(350)	(291)
Retained earnings, December 31	1,184	1,079

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31

(Canadian dollars in millions)	2006	2005
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts – $19 million; 2005 – $14 million) *(Note 14)*	777	628
Materials and supplies	56	56
Other	13	12
	846	696
Fixed assets *(Note 7)*:		
Fixed assets in service	16,238	15,553
Less: accumulated depreciation	6,180	5,818
	10,058	9,735
Construction in progress	468	375
	10,526	10,110
Other long-term assets:		
Deferred pension asset *(Note 11)*	382	449
Regulatory assets *(Note 8)*	311	400
Goodwill	133	133
Deferred debt costs	24	23
Other assets	12	10
	862	1,015
Total assets	12,234	11,821

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets *(continued)*

December 31

(Canadian dollars in millions)	2006	2005
Liabilities		
Current liabilities:		
Bank indebtedness	29	9
Accounts payable and accrued charges *(Note 14)*	661	700
Accrued interest	49	43
Short-term notes payable *(Note 9)*	60	–
Long-term debt payable within one year *(Note 9)*	395	589
	1,194	1,341
Long-term debt *(Note 9)*	4,872	4,466
Other long-term liabilities:		
Regulatory liabilities *(Note 8)*	473	495
Employee future benefits other than pension *(Note 11)*	803	716
Environmental liabilities *(Note 12)*	55	64
Long-term accounts payable and accrued charges	16	23
	1,347	1,298
Total liabilities	7,413	7,105
Contingencies and commitments *(Notes 10, 16 and 17)*		
Shareholder's equity *(Note 13)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,184	1,079
Total shareholder's equity	4,821	4,716
Total liabilities and shareholder's equity	12,234	11,821

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

R. Burak

Rita Burak
Chair

E.A. Mercier

Eileen Mercier
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 (Canadian dollars in millions)	2006	2005
Operating activities		
Net income	455	483
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	474	446
Transmission earnings sharing	33	–
Amortization of discount	27	58
Retail settlement variance accounts	7	12
Low-voltage services	(8)	(24)
	988	975
Changes in non-cash balances related to operations (*Note 15*)	(92)	194
Net cash from operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Termination of interest rate swap	–	(10)
Other	(4)	2
Net cash used in financing activities	(108)	(487)
Investing activities		
Capital expenditures	(823)	(691)
Other assets	15	9
Net cash used in investing activities	(808)	(682)
Net change in cash and cash equivalents	(20)	–
Cash and cash equivalents, January 1	(9)	(9)
Cash and cash equivalents, December 31 (*Note 15*)	(29)	(9)

See accompanying notes to Consolidated Financial Statements.

Note 1.
Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.
Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario) in 2007. The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review Hydro One's transmission rates and to approve revenue requirements for 2006, 2007 and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set. In September 2006, Hydro One Networks filed a transmission rate application. A decision on this application and the resulting revised transmission rates are anticipated in 2007.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. On the basis of the written and oral evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2006 amounted to $586 million (2005 – $577 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.39%; 2005 – 6.80%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated Service Lives (years)	
	Range	Average
Transmission	12–100	55
Distribution	15–75	41
Communication	2–40	19
Administration and service	5–50	39

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt.

Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hedging gains and losses are amortized over the period of the related debt.

The Company does not engage in derivative trading or speculative activities.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.
Electricity Credits to Customers

Under a regulation issued in October 2005, Regulated Price Plan customers received a credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $140 million. The application of the credit did not result in any adjustment to net income.

Note 4.
Depreciation and Amortization

Year ended December 31

Canadian dollars in millions	2006	2005
Depreciation of fixed assets in service	379	369
Fixed asset removal costs	41	41
Amortization of regulatory and other assets	95	77
	515	487

Note 5.
Financing Charges

Year ended December 31

Canadian dollars in millions	2006	2005
Interest on short-term notes payable	2	1
Interest on long-term debt payable	296	297
Amortization of discount	27	58
Other	9	5
Less: Interest capitalized on construction in progress	(28)	(21)
Interest capitalized on regulatory assets	(7)	(10)
Interest earned on investments	(4)	(5)
	295	325

Note 6.
Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31

(Canadian dollars in millions)	2006	2005
Income before provision for PILs	634	681
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	229	246
(Decrease) increase resulting from:		
Net temporary differences:		
Recovery of PILs related to prior years	(30)	(21)
Pension contribution in excess of pension expense	(16)	(25)
Employee future benefits other than pension expense in excess of cash payments	14	8
Transmission amounts received but not recognized for accounting purposes due to earnings sharing mechanism	12	–
Overhead capitalized for accounting but deducted for tax purposes	(11)	(10)
Interest capitalized for accounting purposes but deducted for tax purposes	(13)	(11)
Environmental expenditures	(6)	(5)
Capital cost allowance (in excess of) less than depreciation and amortization	(3)	1
Other	4	1
Net temporary differences	(49)	(62)
Permanent differences:		
Large corporations tax	–	13
Other	(1)	1
Net permanent differences	(1)	14
Provision for PILs	179	198
Effective income tax rate	28.23%	29.07%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized. In 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to utilize the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized. As at December 31, 2006, approximately $2 million of the 2005 amount remains available for use in 2007.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax liabilities of $281 million (2005 – $265 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately $16 million, including the impact of a change in substantively enacted tax rates.

Note 7.
Fixed Assets

December 31 Canadian dollars in millions	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526
2005				
Transmission	8,124	2,889	233	5,468
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	–	421
	15,553	5,818	375	10,110

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $28 million in 2006 (2005 – $21 million).

Note 8.
Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Note 2):

December 31 (Canadian dollars in millions)	2006	2005
Regulatory assets:		
Regulatory asset recovery account I	58	88
Regulatory asset recovery account II	87	92
Employee future benefits other than pension	84	126
Environmental	70	79
Smart meters	10	–
Retail settlement variance accounts	–	11
Other	2	4
Total regulatory assets	311	400
Regulatory liabilities:		
Deferred pension	382	449
Export and wheeling fees	49	32
Transmission earnings sharing	34	–
Retail settlement variance accounts	2	–
Other	6	14
Total regulatory liabilities	473	495

Regulatory Assets

Regulatory Asset Recovery Account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $20 million (2005 – $20 million). In addition, related financing charges would have been higher by $3 million (2005 – $7 million).

Regulatory Asset Recovery Account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $16 million. In addition, related financing charges would have been higher by $5 million.

Employee Future Benefits Other than Pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of two years (2005 – three years) and does not earn a return. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $42 million (2005 – $42 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by $17 million (2005 – $14 million).

Smart Meters

On March 21, 2006, the OEB approved the establishment of deferral accounts for smart meter related expenditures and a monthly customer charge of 30 cents per residential customer was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company has recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In the absence of rate-regulated accounting, the Company's operation, maintenance and administration expense would have been higher by $4 million and revenues would have been higher by $2 million.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $12 million ($2005 – $38 million), assuming no regulatory deferral of distribution and Inergi LP (Inergi) pension-related amounts. In addition, related financing charges would have been higher by $2 million ($2005 – $4 million).

Export and Wheeling Fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of this export and wheeling fee, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006.

Transmission Earnings Sharing

On February 21, 2006, the OEB issued a decision that established an earnings sharing mechanism in which 50% of any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates are set, will be equally split between the Company's shareholder and ratepayers. The excess earnings calculation will be based on the 2006 audited financial statements of Hydro One Networks' transmission business. The application of the earning sharing mechanism will be subject to future OEB review and approval. Any changes resulting from this review will be reflected in results of operations when the OEB renders its decision.

Retail Settlement Variance Accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARV I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARV II. The Company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Note 9.
Debt

December 31

(Canadian dollars in millions)	2006	2005
Short-term notes payable	60	–
Long-term debt:		
4.15% notes due 2006	–	280
4.20% notes due 2006	–	168
4.30% notes due 2006	–	141
4.45% notes due 2007	282	282
4.55% notes due 2007	73	73
4.10% notes due 2007[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	–
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	350
6.59% notes due 2043	315	315
5.00% notes due 2046	75	–
	5,270	5,084
Less: Long-term debt payable within one year	(395)	(589)
Net unamortized premiums (discounts)	9	(14)
Unamortized hedging losses	(12)	(15)
Long-term debt	4,872	4,466

[1] Step-up coupon, after year three from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2006, the notes had a weighted-average interest rate of 4.2%.

Hydro One has a $750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2007, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $1,725 million is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2006, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	395	4.4
2 years	500	4.0
3 years	400	4.0
4 years	400	7.2
5 years	250	6.4
	1,945	5.0
6–10 years	1,050	5.3
Over 10 years	2,275	6.4
	5,270	5.7

Note 10.
Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31

(Canadian dollars in millions)	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	5,270	5,831	5,084	5,697

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into derivative agreements, such as forward fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2006, Hydro One did not enter into any such derivative agreements. In 2005, Hydro One terminated forward interest rate swap agreements entered into in 2005 and 2004 and having a total notional principal amount of $150 million, resulting in a loss of $10 million. The loss is being amortized on an annuity basis over the 30-year term of the related debt.

As at December 31, 2006, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of $40 million and a fair value of $nil ($2005 – $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2006 or in 2005.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2006, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 11.
Employee Future Benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2006 and 2005 was as follows:

	% of Plan Assets	
December 31	2006	2005
Equity securities	64.6	60.6
Debt securities	32.0	36.2
Other	3.4	3.2
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $92 million and $79 million at December 31, 2006 and 2005, respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed $86 million to its pension plan in respect of 2006 (2005 – $83 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuation effective December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2006, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $122 million in 2006 (2005 – $123 million).

Year ended December 31	Pension		Employee Future Benefits Other than Pension	
(Canadian dollars in millions)	2006	2005	2006	2005
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	5,355	4,862	1,143	966
Current service cost	106	83	33	26
Interest cost	267	277	58	57
Benefits paid	(253)	(248)	(36)	(40)
Plan amendments	6	–	22	1
Net actuarial (gain) loss	(70)	381	(120)	133
Accrued benefit obligation, December 31	5,411	5,355	1,100	1,143
Change in plan assets				
Fair value of plan assets, January 1	4,713	4,243	–	–
Actual return on plan assets	571	630	–	–
Benefits paid	(253)	(248)	–	–
Employer's contributions	86	83	–	–
Employees' contributions	17	16	–	–
Administrative expenses	(11)	(11)	–	–
Fair value of plan assets, December 31	5,123	4,713	–	–
Funded status				
(Unfunded benefit obligation)	(288)	(642)	(1,100)	(1,143)
Unamortized net actuarial losses	645	1,069	236	385
Unamortized past service costs	25	22	25	6
Deferred pension asset (accrued benefit liability)	382	449	(839)	(752)
Less: current portion	–	–	36	36
Deferred pension asset (long-term liability)	382	449	(803)	(716)

In January 2007, the Company made a contribution of $8 million in respect of 2006 (2006 – $8 million in respect of 2005).

Year ended December 31	Pensions		Employee Future Benefits Other than Pension	
(Canadian dollars in millions)	2006	2005	2006	2005
Components of net periodic benefit cost				
Current service cost, net of employee contributions	89	67	33	26
Interest cost	267	277	58	57
Actual return on plan assets net of expenses	(560)	(639)	–	–
Actuarial (gain) loss	(70)	381	(120)	133
Plan amendments	6	–	22	–
Other	(1)	–	(1)	–
Costs arising in the period	(269)	106	(8)	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	248	327	–	–
Actuarial loss (gain)	177	(268)	149	(113)
Plan amendments	(3)	3	(19)	–
Net periodic benefit cost	153	168	122	103
Charged to results of operations	42	23	75	64
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	–	–	156	171
Service cost and interest cost	–	–	13	12
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	–	–	(124)	(133)
Service cost and interest cost	–	–	(10)	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.75%	7.00%	–	–
Weighted-average discount rate	5.00%	5.75%	4.98%	5.93%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.75%	2.50%	2.75%
Average remaining service life of employees (years)	10	10	10	10
Rate of increase in health care cost trend	–	–	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.25%	5.00%	5.24%	4.98%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%
Rate of increase in health care cost trend	–	–	4.40%	4.40%

The Company follows the cash basis of accounting. During 2006, pension costs of $86 million (2005 – $85 million) were attributed to salaries of which $42 million (2005 – $23 million) was charged to operations, $24 million (2005 – $22 million) was capitalized as part of the cost of fixed assets, and $20 million (2005 – $20 million) was attributed to a regulatory asset.

a 5.5% in 2006 grading down to 4.4% per annum in and after 2014 (2005 – 5.4% in 2005 grading down to 4.4% per annum in and after 2014).

b 5.25% in 2007 grading down to 4.4% per annum in and after 2014 (2005 – 5.25% in 2005 grading down to 4.4% per annum in and after 2014).

Note 12.
Environmental Liabilities

December 31

(Canadian dollars in millions)	2006	2005
Environmental liabilities, January 1	79	89
Interest accretion	5	5
Expenditures	(17)	(14)
Revaluation adjustment	3	(1)
Environmental liabilities, December 31	70	79
Less: current portion	(15)	(15)
	55	64

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $15 million; 2008 – $14 million; 2009 – $12 million; 2010 – $10 million; 2011 – $7 million; and thereafter – $31 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 13.
Share Capital

Common and Preferred Shares

On March 31, 2006, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,999 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2006, preferred dividends in the amount of $18 million (2005 – $18 million) and common dividends in the amount of $232 million (2005 – $273 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 14.
Related Party Transactions

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2006 includes $1,256 million (2005 – $1,276 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2006 includes $127 million (2005 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2006 includes $21 million (2005 – $21 million) related to these services.

In 2006, Hydro One purchased power in the amount of $2,185 million (2005 – $2,095 million) from the IESO administered electricity market and $38 million (2005 – $36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2006, Hydro One incurred $9 million (2005 – $7 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $15 million (2005 – $11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2006 and 2005.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31

Canadian dollars in millions	2006	2005
Accounts receivable	114	116
Accounts payable and accrued charges	(230)	(263)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $165 million (2005 – $213 million).

Note 15.
Consolidated Statements of Cash Flows

For the purposes of the consolidated statements of cash flows, "cash and cash equivalents" refers to the balance sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31

(Canadian dollars in millions)	2006	2005
Accounts receivable (increase) decrease	(149)	87
Materials and supplies increase	–	(9)
Accounts payable and accrued charges (decrease) increase	(39)	68
Accrued interest increase (decrease)	6	(1)
Long-term accounts payable and accrued charges decrease	(7)	(3)
Employee future benefits other than pension increase	87	62
Other	10	(10)
	(92)	194
Supplementary information:		
Interest paid	302	300
Payments in lieu of corporate income taxes	252	210

Note 16.
Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001

as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by the OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

Note 17.
Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 150 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2006, and in total thereafter are as follows: 2007 – $116 million; 2008 – $98 million; 2009 – $94 million; 2010 – $91 million; 2011 – $87 million; and thereafter – $16 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2006, the Company provided prudential support, using a combination of bank letters of credit of $22 million (2005 – $21 million) and parental guarantees of $275 million (2005 – $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, Hydro One had bank letters of credit of $93 million (2005 – $82 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $5 million; 2008 – $5 million; 2009 – $4 million; 2010 – $1 million; 2011 – $nil; and thereafter – $1 million.

Note 18.
Segment Reporting

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31

Canadian dollars in millions	Transmission	Distribution	Other	Consolidated
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823
2005				
Segment profit				
Revenues	1,310	3,085	21	4,416
Purchased power	–	2,131	–	2,131
Operation, maintenance and administration	353	413	26	792
Depreciation and amortization	246	236	5	487
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	711	305	(10)	1,006
Financing charges				325
Income before provision for payments in lieu of corporate income taxes				681
Capital expenditures	349	338	4	691

December 31

Canadian dollars in millions	2006	2005
Total assets		
Transmission	6,965	6,827
Distribution	5,170	4,902
Other	99	92
	12,234	11,821

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 19.
Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 (Canadian dollars in millions)	2006	2005	2004	2003	2002
Statement of operations data					
Revenues					
Transmission	1,245	1,310	1,262	1,298	1,317
Distribution	3,273	3,085	2,874	2,734	2,682
Other	27	21	17	26	32
	4,545	4,416	4,153	4,058	4,031
Costs					
Purchased power	2,221	2,131	1,987	1,872	1,858
Operation, maintenance and administration	880	792	771	795	832
Depreciation and amortization	515	487	480	454	411
	3,616	3,410	3,238	3,121	3,101
Regulatory recovery	–	–	91	–	–
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006	1,006	937	930
Financing charges	295	325	331	348	353
Income before provision for payments in lieu of corporate income taxes	634	681	675	589	577
Provision for payments in lieu of corporate income taxes	179	198	177	193	233
Net income	455	483	498	396	344
Basic and fully diluted earnings per common share *(Canadian dollars)*	4.366	4.652	4.798	3.779	3.258

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	6,965	6,827	6,785	6,589	6,638
Distribution	5,170	4,902	4,845	4,623	4,694
Other	99	92	95	94	90
Total assets	12,234	11,821	11,725	11,306	11,422
Liabilities					
Current liabilities (including current portion of long-term debt)	1,194	1,341	1,262	1,192	1,894
Long-term debt	4,872	4,466	4,613	4,539	3,938
Other long-term liabilities	1,347	1,298	1,326	1,284	1,451
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	1,184	1,079	887	654	502
Total liabilities and shareholder's equity	12,234	11,821	11,725	11,306	11,422

Year ended December 31 (Canadian dollars in millions)	2006	2005	2004	2003	2002
Other financial data					
Capital expenditures					
Transmission	402	349	432	289	260
Distribution	417	338	288	292	286
Other	4	4	7	16	24
Total capital expenditures	823	691	727	597	570
Ratios					
Net asset coverage on long-term debt[2]	1.92	1.93	1.88	1.86	1.90
Earnings coverage ratio[3]	2.67	2.69	2.70	2.43	2.35
Operating statistics					
Transmission					
Units transmitted *(TWh)*	151.1	157.0	153.4	151.7	153.2
Ontario 20-minute system peak demand *(MW)*[4]	27,056	26,219	25,204	24,849	25,629
Ontario 60-minute system peak demand *(MW)*	27,005	26,160	24,979	24,753	25,414
Total transmission lines *(circuit-kilometres)*	28,600	28,547	28,643	28,621	28,492
Distribution					
Units distributed to Hydro One customers *(TWh)*	29.0	29.7	28.5	27.9	27.1
Units distributed through Hydro One lines *(TWh)*[5]	44.7	45.6	44.8	44.7	45.1
Total distribution lines *(circuit-kilometres)*	122,460	122,118	121,736	121,285	120,767
Customers	1,293,396	1,273,768	1,258,925	1,238,748	1,219,614
Total regular employees	4,295	4,189	4,118	3,967	3,933

[1] Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program.

[2] As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

[3] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[4] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[5] System-related statistics include preliminary figures for December.

[6] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to customers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2006)

Rita Burak [1]
Chair of the Board of Directors, Hydro One Inc.

Sami Bebawi [1,3]
Executive Vice President, Office of the President, President, Socodec Inc., SNC-Lavalin Group Inc.

Murray J. Elston [1,2]
President and CEO, Canadian Nuclear Association

Don MacKinnon [1,3]
President, Power Workers' Union

Eileen A. Mercier [1,2,3]
Corporate Director
Resigned March 30, 2007

Walter Murray [1,2,3]
Corporate Director

Kathleen O'Neill [1,2,3,4]
Corporate Director
Resigned January 24, 2007

Douglas E. Speers [1,4]
Chairman and Director, Enco Corporation

Kenneth D. Taylor [1,3]
Chair, Taylor and Ryan Inc.
Resigned February 27, 2007

Blake Wallace, Q.C. [1,2]
Vice President and Director, Murray & Company
Resigned February 28, 2007

Board Committees

[1] Audit and Finance Committee
The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met five times in 2006.

[2] Corporate Governance Committee
The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2006.

[3] Human Resources and Public Policy Committee
The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met eight times in 2006.

[4] Information Technology Committee
The Information Technology Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met three times in 2006.

[5] Regulatory and Environment Committee
The Regulatory and Environment Committee oversees the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance activities and reports. The committee met five times in 2006.

[6] Health and Safety Committee
The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2006.

[1] Effective March 30, 2007, the following directors were elected to the Board of Directors of Hydro One Inc. by our shareholder: Kathryn Bouey, Laura Formusa, Michael Mueller, Robert Parr, and Gale Rubenstein in place of Eileen Mercier, Kathleen O'Neill, Tom Parkinson, Honourable Bob Rae, Kenneth Taylor and Blake Wallace, who have resigned as members of the Board. As well, the number of directors of the Corporation was reduced from 12 to 11.

Corporate Information

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www.HydroOne.com

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investorrelations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7384

Customer Inquiries
Power outage and
emergency number:
1-800-434-1235

Residential, farm &
small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
Ernst & Young LLP

Design: THE WORKS www.artworksdesign.com

Philanthropy

Making life better for electrical burn patients

In 2006, Hydro One, Sunnybrook Health Sciences Centre and St. John's Rehab Hospital announced the Hydro One Chair in Electrical Injury, a permanently endowed fund to support clinical and academic leadership in the field of electrical injury. Over the next five years, Hydro One has committed $500,000 to push forward research and treatment of electrical burn patients.

"Electrical burns are not very well understood and often the damage they do goes unseen and underscored," said Dr. Joel Fish, Medical Director at the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre. "The research enabled by this funding will do a great deal to improve treatment and rehabilitation for burn patients."

Since 2001, Hydro One and Sunnybrook Health Sciences Centre have worked together to make the expertise of the Ross Tilley Burn Centre available through the hospital's telemedicine capability and the NORTH Network telemedicine network to electrical burn patients across Ontario and Canada. Every year, between 700 and 800 workplace electrical burns occur in Canada, the vast majority of them to workers outside of the electricity sector.

The proper care and treatment for electrical burn patients is important not only to those of us in the electrical industry, but also to workers in every sector.

hydro One

Sunnybrook
HEALTH SCIENCES CENTRE

Dr. Joel Fish
Medical Director, Ross Tilley Burn Centre

hydro One

Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value.